Information Request AG-2-2

Please refer to Exhibit NSTAR-HSP-1, page 2, lines 12 and 13. Please provide copies of all documents relating to Dr. Parmesano's appearances before regulatory authorities on the issue of standby or backup rate design for distributed generation.

Response

Copies of the following prefiled testimony are provided. No other related documents are available.

Testimony and Comments before the Public Service Commission of Nevada, Docket No. 93-11045 on behalf of Nevada Power Company, June 2, 1994 and June 23, 1994 regarding competition, standby rates and environmental externalities in marginal energy costs. (Testimony and Comments were filed, but case settled before hearings.)

Expert testimony before the Illinois Commerce Commission, on behalf of Illinois Power Company, in A. E. Staley Manufacturing Co. v. Illinois Power Company, Docket No. 86-0038, September 12, 1986 and November 25, 1986 regarding standby rates.

Information Request AG-2-3

Refer to Exhibit NSTAR-HSP-1, p. 6, lines 8-20. Please describe how a distribution company should design special contract provisions, including eligibility requirements, and rates that would reflect "the value of the DG project on the network." Would these terms require special metering and communications equipment? How would these customers' costs and revenues be incorporated in rates of other distribution customers? Would the special contract rates for distribution service (delivery and customer related services) reflect a discount or in anyway be lower than the rates charged to non-DG customers of the same size (kW/kVa)? Please explain, in detail, what you would recommend as design guidelines/principles for these types of contracts. To the extent Dr. Parmesano has participated in the development or design of such contracting guidelines or such contracts, please provide copies of these documents (excluding confidential data).

Response

A distribution company should design special contract provisions and eligibility requirements that clearly state the on-site generation characteristics that are of value to the distribution system, how these characteristics will be verified, how the benefits will be quantified, and the method of compensation.

Depending on the generation characteristics that provide the system benefits, special metering and communications equipment might be required. For example, if standby service is interruptible when the local circuit or substation is close to being fully utilized, special equipment may be needed to notify and/or remotely curtail standby service to the customer.

The costs and revenues of these standby customers with special contracts would presumably be treated as other special contracts are treated.

There are several ways to reflect on-site generation benefits to the distribution system in special contracts. For example, certain charges in the standard standby charges could be discounted. Another possibility is that credits could be given for performance (curtailing standby demand during peaks on local distribution facilities, for example).

The principles guiding negotiation of such special contracts should include the establishment of payments/discounts to the on-site generation that reflect the net benefits of the on-site generation's presence and operation to the distribution system.

Dr. Parmesano is participating in settlement negotiations among Portland General Electric Company, the Oregon PUC staff, and a large cogenerator. She is not at liberty to release materials related to the negotiations.

Information Request AG-2-4

Has Dr. Parmesano presented testimony supporting a fully allocated (to discrete customer classes) embedded cost of service study to be used in the design of electric utility rates? If yes, please provide a copy of the study, the related testimony and the related regulatory commission orders.

Response

Yes. Please see Dr. Parmesano's testimony to the Salt River Board, Attachment AG-2-4. The embedded cost study cannot be provided because it is confidential and proprietary. A copy of the Board's decision is not available to Dr. Parmesano.

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Att. AG-2-4

n/e/r/a
Consulting Economists

Review of Salt River Project Proposed Electric Price and Service Plan Changes Effective December 31, 1998

prepared by

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Vice President

October 1, 1998

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San Francisco, CA / Seattle, WA / Washington, DC / White Plains, NY
A MARSH & McLENNAN COMPANY

Executive Summary

NERA was engaged by the Board of Directors (Board) of the Salt River Project (SRP) to review Management's proposed electric price plans and provide recommendations to the Board. This year's price adjustments are far more complex than in past years. Because of the phasing in of retail open access beginning on December 31, 1998, SRP must offer two sets of prices to its customers – one set of bundled prices for customers who continue to buy both generation service and delivery from SRP, and a second set of unbundled prices for customers who choose to have SRP deliver generation they have purchased from another supplier. In addition, the requirements of HB 2663 to cap[1] class average prices at their December 30, 1998 level until December 31, 2004 and to reduce bundled prices by ten percent over a ten-year period mean that the revenue level established by the new prices is particularly critical.

The focus of NERA's review has been on (1) the proposed class allocations, (2) the proposed price plans, (3) the cost studies[2] on which they are based, and particularly (4) the relationship between the bundled and unbundled prices. We did not perform an independent financial analysis of SRP's revenue requirement. It is our understanding that SRP's accountants and financial advisors have analyzed the financial implications of Management's proposed revenue reduction, including the Board's approach to retail access and stranded cost recovery.

Management has identified several objectives for the proposed prices: compliance with HB 2663 and the Board's directives on Customer Choice, prices better reflective of cost structure, enhancement of SRP's competitive position, good financial performance, and facilitation of a smooth transition to competition. All of these objectives are reasonable and will contribute to SRP's and its customers' ability to make the transition to competition.

Management proposes a 4.5-percent overall reduction in revenues, and a 4.5-percent average price reduction to each major customer class. It is not the role of an economic

[1] Except for the pass-through of certain new costs in a system benefits charge.

[2] Historical Cost Allocation (HCA) and unbundling of the HCA by function and price class were reviewed for general methods, but not for specific calculations.

consultant to determine the appropriate weights to be given to cost of service, equity considerations, competitive conditions and other pricing objectives; however, under the circumstances, with the possible exception of the lighting class, the equal reduction approach seems reasonable.

Within the major customer classes, Management has proposed differential price reductions and even one price increase. These differences by price plan are designed to reduce or eliminate disparities among the price plans within a class. The residential and general service TOU prices were adjusted so that the average load curve of their non-TOU counterpart price plan would produce the same (or nearly the same) revenue when billed at the TOU or non-TOU prices. The increase in the E-56 price plan is designed to improve cost recovery of the lighting equipment installed for these customers. The E-63 prices were reduced more than the E-61 prices to remove an uneconomic incentive for customers to purchase their transformers in order to move from E-61 to E-63 and to move the energy prices for these price plans more in line with market prices. These differential adjustments are all reasonable.

The consultant's review of the historical cost allocation (HCA) indicates that there are several aspects that could be improved in future studies, given better information. Because the results of the HCA were not used to allocate the price reduction to classes or to justify differential reductions/increases for price plans within classes, these aspects do not have a critical bearing on the revenue allocation portion of this proceeding.

A new component of the HCA adjusts the FY 97 figures to reflect FY 00 conditions and functionalizes the costs allocated to each class. This study forms the basis for the unbundled prices. Customers choosing alternative suppliers pay, in the unbundled prices, all components of the bundled prices except the "shopping credit," and, if they are large customers and choose a competitive supplier of metering and billing services, these revenue cycle services charges. Thus, the unbundling of distribution, transmission and ancillary services supplied by SRP does not affect the customer's bill. SRP's unbundling study provides a reasonable basis for unbundling the prices.

The proposed changes in bundled prices are entirely appropriate. They are consistent with Management's pricing goals, responsive to the competitive environment, and create acceptable bill impacts. The proposed prices would simplify a number of price plans, make the charges better reflect the structure of costs, and reflect market prices to a greater degree.

SRP's unbundled prices are designed for use by customers who have chosen another supplier of generation services. These prices must recover SRP's cost of providing regulated delivery service and metering and billings services (for customers who are purchasing metering and billing services from SRP), and a contribution to strandable costs. There are legal and economic factors that should govern the design of unbundled prices. The consultant found that Management's proposal would adequately inform customers of the amount they would save on their SRP charges if they chose another supplier. The transmission and ancillary service charges in the unbundled prices are appropriately tied to SRP's wholesale transmission prices, consistent with FERC policy.

However, there are three problems with the unbundled prices. First, the shopping credits for the industrial customers are larger than the likely market price of generation and competitively offered ancillary services. The savings to these customers from switching from bundled to unbundled prices are almost guaranteed to provide them with significant savings. When this happens, SRP will be left with stranded costs greater than the CTC included in the unbundled prices.

The second problem with the unbundled prices is the development of single unbundled price plan for use by residential, commercial and pumping customers. It appears that the lack of an unbundled price plan for each bundled plan may make it uneconomic for some customers to move to the competitive market.

The third problem is the use of average historic costs to set the unbundled prices for revenue cycle services. This practice could lead to stranded metering and billing system costs. SRP should reconsider the cost basis for unbundled revenue cycle services before these services become competitive for all customers, to the extend alternatives would be consistent with HB 2663.[3]

In summary, Management's proposed prices are reasonably designed to achieve the stated objectives, with the possible exception of (1) the price reduction for the lighting class (which is far from covering its cost of service even under current prices), (2) the lack of unbundled prices corresponding to each bundled price, (3) the inflated shopping credits for industrial customers choosing another supplier, and (4) the average cost basis for the revenue cycle service unbundled prices.

[3] Charging incremental or avoided rather than average historic cost for these services would protect SRP from stranded revenue cycle costs and allow the utility to compete with unregulated suppliers of these services.

Review of Salt River Project
Proposed Electric Price and Service Plan Changes

I. INTRODUCTION

NERA was engaged by the Board of Directors (Board) of the Salt River Project (SRP) to review Management's proposed electric price plans and provide recommendations to the Board. This year's price adjustments are far more complex than in past years. Because of the phasing in of retail open access beginning on December 31, 1998, SRP must offer two sets of prices to its customers – one set of bundled prices for customers who continue to buy both generation service and delivery from SRP, and a second set of unbundled prices for customers who choose to have SRP deliver generation they have purchased from another supplier. In addition, the requirements of HB 2663 to cap[4] class average prices at their December 30, 1998 level until December 31, 2004 and to reduce bundled prices by ten percent over a ten-year period mean that the revenue level established by the new prices is particularly critical.

The focus of NERA's review has been on (1) the proposed class allocations, (2) the proposed price plans, (3) the cost studies[5] on which they are based, and particularly (4) the relationship between the bundled and unbundled prices. We did not perform an independent financial analysis of SRP's revenue requirement. It is our understanding that SRP's accountants and financial advisors have analyzed the financial implications of Management's proposed revenue reduction, including the Board's approach to retail access and stranded cost recovery.

Because of the tight time schedule for this proceeding, coming so close to the completion of the Customer Choice process, it was not possible for the consultant to review

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4 Except for the pass-through of certain new costs in a system benefits charge

5 Historical Cost Allocation (HCA) and unbundling of the HCA by function and price class were reviewed for general methods, but not for specific calculations. In past reviews of Management's price proposals, NERA has not examined the HCA at all. This year, because the unbundled prices are based on the HCA, NERA did review and comment on the cost studies.

final versions of the cost studies and price designs before preparing this report. However, Management did keep the consultant informed of last-minute changes being made.

II. PRICING OBJECTIVES

Management has noted several objectives for their pricing redesign proposal.

- The first objective is to comply with HB 2663. This is clearly an important legal requirement and an appropriate objective to be given high priority.
- The second objective is to comply with Board directives related to HB 2663 requirements. These instructions detail how SRP will implement retail access and recover SRP's strandable costs.
- The third objective is to restructure prices to better reflect costs, share savings in operating costs, and reduce or eliminate intraclass subsidies.
- The fourth objective is to improve customer perceptions of the value in SRP service and to better position SRP competitively. Achievement of this objective should contribute to SRP's financial performance (Objective 5).
- The fifth objective is to maintain SRP's financial performance.
- The sixth objective is to promote a smooth transition to competition.

Comment: All of these objectives are reasonable and will contribute to SRP's and its' customers' ability to make the transition to a competitive industry.

III. CLASS REVENUE REDUCTIONS

On June 1, 1995 SRP implemented an overall 4.5-percent price reduction for large general service (industrial) customers, followed in 1996 by an overall 3.4-percent average price reduction for smaller customers. These differential price reductions were justified on the basis of cost of service and, to a certain extent, competitive conditions. The net effect of price changes in 1995 and 1996, plus changes in 1991 and 1992, was a system average reduction of

4.6 percent. Management has proposed a further reduction in average prices of 4.5 percent, to be effective December 31, 1998.

In the past, allocation of price increases and decreases to broad customer classes (residential, commercial, pumping, lighting and industrial) have been based on the results of historical costs allocations (also known as embedded cost studies), tempered by competitive conditions, customer impacts, and political considerations. The spread of increases or decreases to the individual price plans within broad customer classes took these factors, as well as economic efficiency, into account.

In this proceeding, new factors must be considered in determining how the overall price decrease is allocated to the various customer classes and price plans: (1) the requirements of HB 2663 and (2) the effect of the allocations, combined with the unbundled prices for customers choosing to exercise retail access, on SRP's revenues.

According to SRP's interpretation of HB 2663, the required ten-percent reduction in bundled prices over ten years applies to average prices, not to individual classes or price plans. SRP has chosen to start the ten-year clock at January 1, 1991. This means that in addition to the overall cumulative 4.6-percent price reduction since January 1, 1991 and the 4.5-percent overall proposed in this proceeding, an additional 0.9-percent overall reduction will be necessary before December 31, 2000. To assure that all customer classes share in the benefits of coming competition, Management proposes to give each customer class a 4.5-percent reduction in this price adjustment. The allocations to the individual price plans vary to take other pricing objectives into account.

The reductions by class from January 1991 to date, and with the proposed 4.5-percent reductions, and the proposed relative historical cost recovery[6] are shown in the following table.

[6] 100 percent indicates full cost recovery, including the system average return on adjusted committed capital (excluding interest-earning assets). The recovery for the pumping class reflects normalized consumption.

Class	Price Reductions 1991 – present	Proposed Reduction	Cumulative Reduction	Proposed Relative Cost Recovery
Residential	3.2%	4.5%	7.7%	90%
Commercial	5.3	4.5	9.8	115
Pumping	3.9	4.5	8.4	102
Lighting	3.6	4.5	8.1	70
Industrial	~~4.9~~ 8.5	4.5	~~9.4~~ 13.0	110
TOTAL	4.6	4.5	9.1	100

At this critical juncture in the history of Arizona's electric industry, Management chose to recommend giving highest weight to equity (equal sharing of the price reduction among classes), with no adjustment at the class level for differential degrees of cost recovery. This is the type of value judgment that the Board is elected to make. However, giving a 4.5-percent price reduction to the lighting class, who would be paying only 70 percent of its relative cost of service under proposed prices, does require further explanation by Management. This reduction would bring the cumulative reductions since January 1, 1991 for the lighting class to 8.1 percent, compared to 7.6 percent for residential customers (who would be paying much closer to relative full cost of service).

Comment: It is not the role of an economic consultant to determine the appropriate weights to be given to cost of service, equity considerations, competitive conditions and other pricing objectives; however, under the circumstances, with the possible exception of the lighting class, the equal reduction approach is reasonable.

Although Management's proposal gives equal price reductions to each broad customer class, the reductions for the various price plans vary significantly, as shown in the table below:

Proposed Price Reductions by Price Plan	
E-23 – Residential Basic Plan	4.69
E-26 – Residential Time of Use	3.54
E-24 – Residential Pay As You Go	2.75
E-32 – General Service TOU	10.20
E-36 – Standard General Service Plan	4.42
E-47 – Standard Pumping Plan	4.40
E-48 – Time-of-Week Pumping Plan	4.80
E-54 – Traffic Signal Lighting Service	19.00
E-56 – Standard Lighting Service	-3.20
E-55 – Playground Lighting Service (frozen)	0.00
E-61 – Secondary Large General Service	2.90
E-63 – Primary Large General Service	8.80
E-65 – Dedicated Large General Service	4.50

These differences by price plan are designed to reduce or eliminate disparities among the plans within a class. The residential and general service TOU prices were adjusted so that the average load curve of their non-TOU counterpart plan would produce the same (or nearly the same) revenue when billed at the TOU or non-TOU prices. The increase in the E-56 plan is designed to improve cost recovery of the lighting equipment installed for these customers. The E-63 prices were reduced more than the E-61 prices to remove an uneconomic incentive for customers to purchase their transformers in order to move from E-61 to E-63 and to move the energy prices for these plans more in line with market prices.

Comment: The revenue changes by price plan are reasonable.

IV. HISTORIC COST ANALYSIS

The SRP historical cost allocation (HCA) model prepared for this price adjustment uses methods largely the same as those used in past years. However, the requirements of HB 2663 necessitated an expansion to include more detail by function and class. The cost model is a work in progress. SRP's analysts would like to make improvements to it, but were not able to given the press of other work created by the Customer Choice process and the advent of retail access.

The SRP HCA uses several non-standard approaches. The concept of rate base, on which rate of return is computed, is approximated in the SRP HCA. The consultant recommends that in future studies a more precise computation of rate base be included.

SRP's HCA allocates distribution substation costs on the same basis as transmission costs and the "excess" portion of production costs, i.e., using class contribution to the four summer system peaks. In most utility systems, distribution substations do not all peak coincident with the system. As a result, the more common allocator is class relative non-coincident peak, which gives a greater cost responsibility to classes that peak outside the system peak (such as lighting and possibly industrial). Since distribution substations often serve more than one class, an even more precise allocator would take into account the contribution of classes to the peaks on the substations they use. The consultant recommends that other allocation techniques be explored when better data is available.

Comment: Management's HCA is reasonable. Because the results of the HCA were not used to allocate the price reduction to classes or to justify differential reductions/increases for price plans within classes, the minor problems in the current HCA approach do not have a critical bearing on the revenue allocation portion of this proceeding.

SRP has developed a separate model to unbundle its allocated costs by function. The unbundling analysis starts with the costs allocated to classes in the HCA. It then adjusts FY 97 figures to better reflect costs in FY 00. The revenues implicit in the bundled prices for each class are then divided into functions. Transmission, ancillary services[7], and revenue cycle services costs are set at full embedded cost, including a rate of return equal to SRP's weighted-average cost of capital. The generation component consists of a CTC, allocated on the basis of the average-and-excess factors used in the HCA for total generation costs[8], and a "shopping credit" – the difference between charges under bundled and unbundled prices for the class. The distribution component of the class revenues (and the implicit return on distribution rate base) then becomes a residual.

The methods in SRP's unbundling analysis are reasonable. Because customers on unbundled prices will pay all elements of the unbundled price (except for large customers who are allowed to purchase revenue cycle services competitively), the functionalization is largely cosmetic.

Comment: SRP's unbundling study is reasonable.

V. BUNDLED PRICES

The proposed changes in bundled prices are entirely appropriate. They are consistent with Management's pricing goals, responsive to the competitive environment, and create acceptable bill impacts.

If experience in other deregulated industries is applicable to the electric industry, competition will lead to price simplification.[9] In this price adjustment proceeding, SRP Management proposes a number of changes that will simplify prices, including: (1) elimination or flattening of block prices, (2) elimination of demand charges for some customers, (3) incorporation of riders into price plans, (4) elimination of the fuel cost adjustment factor, (5) elimination of the service charge in the Pay As You Go Rider, and (6) elimination of obsolete or little-used prices. These are all steps in the right direction.

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[7] Those ancillary services that must be purchases from SRP (scheduling and voltage control).

[8] The total amount of CTC revenue was determined in the Customer Choice settlement process.

[9] Consider the "ten cents a minute" offers from long-distance telephone providers.

Competition will increase the need for price complexity in two respects. First, customers paying both bundled and unbundled prices are required to pay the same system benefits charge (SBC). It is important that the amount of this charge be shown clearly on the price plans for both bundled and unbundled service so that it is possible to verify that both types of customers are being charged uniformly for the costs of social programs. SRP Management plans to show the SBC on the bills of customers taking unbundled service and as a footnote on the price plans for bundled service.

The other need for complexity introduced by competition is for customers taking bundled service to know what they would continue to pay SRP if they were to choose another energy supplier. This information is essential in order for customers to be able to evaluate offers from competing suppliers. SRP Management plans to provide this information in the newsletters sent to customers each month.

SRP Management's proposal to increase fixed charges and reduce variable charges to better reflect the structure of costs is an important first step. Additional shifts should take place in future price adjustments. Such shifts are important to reduce intraclass subsidies, give better price signals, and ensure cost recovery for SRP's transmission and distribution business.

Another set of proposed changes designed to better align prices with costs is the move to use market-based prices in the Real Time Pricing (RTP) Pilot Rider, the Standby Rider for Qualified Cogeneration and Small Power Production Facilities, and the Buyback Service Rider. Under Management's proposal, each of these riders would include a component computed on a day-ahead basis or after-the-fact from actual market prices. The interruptible rider credits would also be brought more in line with the market value of interruptibility, over time.

There are a number of special discounts or increased discounts proposed for selected customers. These include: (1) conversion of the percentage discounts for low-income and life-support customers to a flat monthly bill credit, and the removal of the usage limitation and age restrictions; (2) extension to residential customers of the SurePay program -- a one-percent credit for allowing SRP to withdraw funds from their checking account; and (3) aggregation discounts for customers with multiple accounts totaling a certain minimum size who agree to purchase all electricity requirements from SRP for a specific period of time. The flat monthly credit for low-income customers is a more efficient price design than a discounted price because it gives better price signals. The discounts for SurePay and aggregation are designed to improve customer perceptions of SRP and make SRP a more competitive supplier. Management has estimated participation in all three programs (assuming 20 to 25-percent participation in the low-income program, 100-percent participation in SurePay and aggregation by all eligible customers) and has taken the discounts into account in computing the 4.5-percent average reductions for each class. Therefore, these discounts are unlikely to create financial risk for SRP.

Comment: The proposed bundled prices are appropriate.

IV. UNBUNDLED PRICES

SRP's unbundled prices are designed for use by customers who have chosen another supplier of generation services. These prices must recover SRP's cost of providing regulated delivery service and metering and billings services (for customers who are purchasing metering and billing services from SRP), and a contribution to strandable costs. There are regulatory and economic factors that should govern the design of unbundled prices.

- First, there should be a clear relationship between the bundled and unbundled prices applicable to each customer class so that customers can easily compare SRP's price for generation with other offers they may receive.
- Second, unbundled prices must be structured so that customers pay the same for regulated services (and CTC), whether or not they are buying generation services from SRP. This means that a customer must not see an increase in the delivery portion of its bill just because it has chosen to exercise its ability to purchase generation (and competitive ancillary) services elsewhere. This could happen if the shopping credit (the difference between the bundled and unbundled charges) was less than the market price of plain vanilla energy (without hedges). Customers

would find it uneconomic to shift to another supplier because the unbundled delivery prices exceeded the non-generation elements of the bundled prices.

- Third, FERC has jurisdiction over prices for transmission and ancillary services and requires that retail customers be charged (to the extent possible given metering constraints) the same transmission and ancillary service prices as those charged to wholesale customers.[10] SRP's wholesale transmission prices are demand charges derived from an allocation of annual transmission costs using class contribution to the four coincident peaks, but recovered 1/12 each month. Ideally the wholesale prices should only be converted to cents/kWh charges for non-demand-metered customers.
- Fourth, care must be taken in identifying unbundled metering, meter-reading and billing prices. If SRP does not avoid its average level of these costs when a customer chooses another supplier of these services, stranded metering and billing costs will be created.
- Fifth, if the difference between bundled and unbundled prices significantly exceeds the cost SRP avoids by not having to supply generation services (essentially the market price of energy and competitive ancillary services), customers will have a large incentive to choose another supplier and SRP will have stranded costs not covered by the CTC.

Do the proposed unbundled prices adequately address the factors necessary to meet regulatory and economic requirements? Let us examine them, one factor at a time.

[10] FERC does allow for the possibility of some other arrangement for retail transmission and ancillary service charges, but any deviation must be approved by FERC and must remain consistent with FERC's goal of comparable charges for retail and wholesale customers.

Information about the Relationship to Bundled Prices

Under Management's proposal, customers on bundled prices will be informed through newsletters and other media what portion of their bundled prices are SRP's charges for generation services. This should enable them to evaluate offers from other suppliers.

Equal Delivery Prices in Bundled and Unbundled Prices

If delivery charges are the same in bundled and unbundled prices applicable to a customer, the differential between the two prices (the shopping credit) should be approximately equal to the market price of generation (and competitive ancillary) services. This market price will vary depending upon the time pattern of the class' usage and its load factor. For each unbundled price plan except the E-60 prices, Management set the shopping credit at the estimated average market price corresponding to the plan's load curve.

Each of SRP's bundled price plans corresponds to an unbundled price plan. In an effort to simplify retail access, Management has proposed a single unbundled price plan for residential customers, a single unbundled price plan for general service customers and a single unbundled price plan for pumping customers, even though there are two bundled prices for each of these classes. If there were an unbundled price for every bundled price and the shopping credit accurately reflected the market price of generation for the average load curve in the plan, the average customer in each plan would be indifferent to buying from SRP or an alternative supplier. Because SRP has chosen to provide composite unbundled prices for residential, commercial and pumping customers, the average customer on each bundled price will not be indifferent. This means that fewer customers will find it economic to go to the market than would do so if each price plan had an unbundled counterpart. While the goal of simplification is important, Management's proposal may be discriminating against some customers by not unbundling each bundled price individually.

The table below shows estimates of the shopping credit implicit in each of Management's proposed bundled/unbundled price plan pairs.

Price Plan	Average Shopping Credit (cents/kWh)	
	Summer	Winter
E-23	3.52	2.49
E-26 res, TOU	2.47	2.33
E-36	3.22	2.37
E-32 = GS TOU	1.91	1.77
E-47	3.21	2.37
E-48	3.21	2.37
E-54	2.08	2.08
E-56 -St. Lighting	1.94	1.94
E-61	3.70	2.61
E-63	3.56	2.46
E-65	3.65	2.58

The large shopping credits proposed for the E-60 series customers are likely to mean that all of these customers will choose alternative suppliers, leaving SRP with stranded costs not recovered in the CTC. The small credits for E-32 customers means they are unlikely to be able to participate in the competitive market.

Comment: The composite unbundled prices for residential, commercial and pumping customers may artificially discourage some customers from going to the market for generation services. The shopping credits implicit in the unbundled prices for E-60 series customers are likely to lead to unrecovered stranded costs. The Board should be aware that the inflated shopping credits could cause revenue erosion.

Consistency between Retail and Wholesale Transmission and Ancillary Service Charges

FERC's standard transmission pricing policy is to allocate annual transmission costs on the basis of contribution to system peaks (either 4 or 12 months peaks), and recover the allocated costs in 12 equal monthly installments. Customers without demand metering cannot pay on a demand basis, but the costs can be allocated on this basis. In unbundling transmission and ancillary service charges, SRP has followed the FERC prescription appropriately.

Cost Basis For Unbundled Metering, Meter-reading and Billing Services

SRP's unbundled HCA is the basis for unbundled metering, meter-reading and billing services. Only the largest customers are eligible to purchase these services from another supplier. However, when these revenue cycle services become competitive for all customers, this average embedded cost approach to pricing them may leave SRP with stranded meter, meter-reading and billing system costs.

Comment: SRP should reconsider the cost basis for unbundled revenue cycle services, provided alternatives are possible under HB 2663, before these services become competitive for all customers.[11]

Potential for Revenue Erosion

Ideally, unbundled **prices** should differ from bundled **prices** only by the market value of generation (and competitive ancillary) services. A larger differential pushes customers to find other suppliers and leaves the utility with unanticipated stranded costs. (This is particularly the case for SRP, which is not allowed to recover more that the stranded cost amount approved in the settlement.) As explained above, the very large shopping credits proposed for some unbundled **prices** are very likely to cause revenue erosion.

V. FINANCIAL RISK FROM PRICE REVISIONS

SRP's financial advisors and accountants are comfortable with Management's proposed overall revenue reduction and treatment of stranded cost recovery. Management's calculations indicate that at expected sales levels, proposed prices will produce the target level of revenue. However, there is an added degree of uncertainty in both cost and revenues as a result of the proposed prices. An important issue for the Board to consider is whether this uncertainty has been factored into Management's plans.

[11] Charging incremental or avoided rather than average historic cost for these services would protect SRP from stranded revenue cycle costs and allow the utility to compete with unregulated suppliers of these services.

Elimination of the fuel escalator, which allows SRP to adjust prices for changes in the costs of fuel and purchased power between base price adjustment proceedings, removes a risk management tool from SRP's toolbox. Management assures us that the SRP price/risk management group has evaluated the impact of this change and is comfortable that the increased risk is acceptable.

Extension of the low income subsidy to households other than those with elderly members may attract more participants than currently estimated. Because the cost of the subsidy is part of the system benefits charge, which is adjustable outside the price cap, SRP can recover the cost of the extra subsidy in future adjustments to the SBC.

As described above, loss of E-60 series loads, because of the high shopping credits in the unbundled prices for these customers, is a serious threat.

Comment: The shopping credits to industrial customers should be reduced or the revenue losses resulting from them taken into consideration in setting the price reductions for other classes.

Information Request AG-2-8

Has Dr. Parmesano reviewed the Companies' cost of service studies used to develop the current distribution rates? Based on Dr. Parmesano's understanding of the costs included in each distribution rate element, are the Company's standby rates, as originally proposed, cost based?

Response

Dr. Parmesano has not reviewed the Companies' cost of service studies.

Information Request AG-2-9

Dr. Parmesano makes the distinction between the proposed standby tariffs for generators of at least 1MW and smaller DG customers. She differentiates these categories by characterizing the 1MW standby rate as incorporating a monthly charge per kW of contract demand for all non-customer-related distribution costs and characterizing the standby rate proposal for small DG customers as having "a combination of contract demand charges (for local distribution facilities costs) and monthly peak demand charges (for local distribution substation costs). See page 13 of Exhibit NSTAR-HSP-1. Is it Dr. Parmesano's opinion that this is the most appropriate rate design for standby rates or only appropriate in this case? If the later, please explain how standby rates should be designed, ideally.

Response

Dr. Parmesano believes that standby rates should be designed: (i) using the same costing principles used to design rates for continuous-use customers; (ii) recovering on a fixed basis distribution costs that do not vary with the amount of energy delivered on a standby basis to on-site generating customers; and (iii) recovering on a usage basis costs that do vary with standby usage. Depending on factors such as the size and other characteristics of the standby customers, and on the engineering practices of the utility in question, these principles can result in different appropriate standby rate structures in different jurisdictions.

Information Request AG-2-10

What is Dr. Parmesano's opinion regarding interruptible rates for DG customers? How should interruptible rates be designed for the Companies? What specific eligibility requirements should be incorporated in such tariffs? Has Dr. Parmesano participated in the design of tariffs or contracts for interruptible distribution service? If yes, please describe the circumstances and the result of such efforts.

Response

This question seeks information that is beyond the scope of Dr. Parmesano's rebuttal testimony. Having said that, Dr. Parmesano believes that the general approach discussed in Mr. LaMontagne's direct testimony wherein these issues would be subject to negotiation on a case-by-case basis is reasonable particularly until requests for such service increase.

Information Request AG-2-11

Refer to Exhibit NSTAR-HCL-7, page 15, lines 16-21. Did the Company consider phasing-in all DG or generating customers on to the proposed rates? If not, why? If yes, why did it decide to permanently grandfather these customers? Please explain based on the differentiation between large DG (>1MW) and small DG (<1MW>60kW).

Response

Yes, it did. The Company determined that it would grandfather the existing customers because it generally seemed unfair to begin applying new significantly redesigned standby rates to customers that had made prior investments based upon the then-existing design of standby rates.

Information Request AG-2-12

Refer to Exhibit NSTAR-HCL-7, pages 17-18. Is it Mr. LaMontagne's opinion that demand ratchets are inappropriate for transmission rates? Please explain.

Response

Yes. As Mr. Salamone explains in his testimony, there is relatively more diversity between individual customer maximum loads at the aggregate transmission level than at distribution levels closer to the individual customers. Accordingly, individual customer maximum demand, which is the quantity subject to a fixed demand level, contributes relatively less to the determination of transmission capacity needs. For the purposes of rate simplicity and understanding, the cutoff point for applying a fixed demand level reasonably is limited to the distribution system.

Information Request AG-2-13

Refer to Exhibit NSTAR-HCL-7, page 21. Please provide documentation that the allocation of sub-station costs used in the revised standby rates is consistent with the allocation of these costs to the affected classes based on the Companies' cost of service studies from the last base rate cases.

Response

Please see Attachment AG-2-13, which sets forth the distribution investment by account for the years in each company's last base rate case.

NSTAR Electric
Distribution Investment

Cambridge Electric Light Company (1991)

Account #		Total	HT %		High Tension
360	$	256,984	100.0%	$	256,984
361	$	2,584,534	100.0%	$	2,584,534
362	$	23,791,391	100.0%	$	23,791,391
364	$	1,514,429	0.0%	$	-
365	$	4,004,253	0.0%	$	-
366	$	13,856,179	54.0%	$	7,482,337
367	$	23,253,348	55.9%	$	12,998,622
368	$	2,364,749	0.0%	$	-
Total	$	71,625,867	65.8%	$	47,113,867
% Substations (Accounts 361+362)		36.8%			56.0%

Boston Edison Company (1991)

Account #		Total	HT %		High Tension
360	$	8,687,000	100.0%	$	8,687,000
361	$	33,528,000	100.0%	$	33,528,000
362	$	167,145,000	100.0%	$	167,145,000
364	$	50,545,000	32.4%	$	16,371,526
365	$	147,261,000	29.7%	$	43,795,421
366	$	96,294,000	64.1%	$	61,676,307
367	$	329,137,000	64.1%	$	210,812,249
368	$	168,059	3.0%	$	4,975
Total	$	832,765,059	65.1%	$	542,020,477
% Substations (Accounts 361+362)		24.1%			37.0%

Commonwealth Electric Company(1989)

Account #		Total
360	$	2,334,877
361	$	256,353
362	$	8,004,825
364	$	43,592,500
365	$	55,017,793
366	$	10,983,559
367	$	40,238,036
368	$	50,239,809
Total	$	210,667,752
% Substations (Accounts 361+362)		3.9%

Note: FERC Form1 , PIS page 206

Information Request AG-2-14

Does Mr. LaMontagne agree with Dr. Parmesano's testimony that substation costs should be collected through time differentiated charges based on use? (Exhibit NSTAR-HSP-1, page 10) If not, please explain any differences in opinion?

Response

Yes. Mr. LaMontagne's understanding of Dr. Parmesano's testimony is that "use" can refer to per kW charges. For NSTAR Electric's large demand-metered general service rates, demand charges are appropriate.

Information Request AG-2-15

Does Mr. Salamone agree with Dr. Parmesano's testimony that substation costs should be collected through time differentiated charges based on use? (Exhibit NSTAR-HSP-1, page 10) If not, please explain any differences in opinion?

Response

Please see the response to Information Request AG-2-14.

Information Request AG-2-16

Refer to Exhibit NSTAR-HSP-1, pp. 10-11, lines 21-23. Has any NSTAR electric company conducted any study or analyses of its distribution sub-stations (account 361 and 362 plant) to confirm that the conditions described in Dr. Parmesano's testimony as exemptions to the as-used cost recovery rate design principal **do not** exist? If yes, please provide all such studies and explain whether these results may be considered representative of other service areas.

Response

In his testimony, Mr. Salamone explains that, where there are standby loads of 1 MW or greater, the substation is sized to handle the full standby load at the time of the substation peak. Such substations do, in fact, exist in the Company's service territory.

Information Request AG-2-17

Refer to Exhibit NSTAR-HCL-7, pp. 28-29. Please explain how the Company has billed customers under the SB-1 and MS-1 tariffs. Were customers billed transition charges and charge for first kVA block? If not, please explain how the Company accounted for the lost transition revenue.

Response

The customer taking service under Cambridge's Rate SB-1 and Rate MS-1 was billed the transition charges, as approved by the Department. The demand charges for Rate SB-1 are not blocked. Accordingly, all standby demands were billed using the relevant demand charges set forth on the applicable rate schedule.

Information Request AG-2-18

Refer to Exhibit NSTAR-HCL-7, p. 29. Please explain how Mr. LaMontagne determined that 20% was an appropriate threshold to incorporate in the Companies' modified rate proposal. Include all supporting documentation, calculations and assumptions.

Response

The 20 percent threshold was chosen for two reasons. First, it is consistent with the existing threshold set forth in Cambridge's currently effective Rate SB-1. In addition, an examination of Exhibit NSTAR-HCL-8 shows that most customers exhibit an average to maximum billing demand ratio of between 70 percent and 90 percent. This represents the normal range of variability in customers' monthly billing demands. Accordingly, it is reasonable to exempt from standby rates, on-site generation customers whose standby loads would result in a similar level of load variability.